

Integrating Independent Power Producers into Emerging Wholesale Power Markets

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Policymakers wishing to introduce wholesale competition into the electricity industry must often reconcile existing independent power producer contracts with new market structures and trading arrangements. For the new market arrangements to bring the benefits of competition to consumers, enough participants must be willing to take market risk. A combination of measures—adaptation of specific market rules, contractual alternatives for enhancing market liquidity, contract buyout provisions, transitional financing mechanisms—offer promise for reconciling existing contracts with new market structures and reducing the magnitude of above-market costs associated with the contracts.

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Summary findings

Many developing and industrial countries have sought to open their electricity industries to competition. In both contexts, policymakers and investors have to deal with the consequences of earlier, more partial sector liberalization measures. Foremost among these is the existence of long-term contracts with independent power producers (IPPs). The long-term nature of these contracts has complicated the introduction of more far-reaching sectoral reform designed to harness competitive market forces for the benefit of consumers.

In developing countries, introducing competition is often coupled with breaking up and privatizing state-owned electricity monopolies. In this context, discussion of renegotiation of power purchase agreements has tended toward the polemical. At one end are those who resist any change, arguing that the “sanctity of contracts” precludes modification of contract terms. At the other end are those who favor governments taking coercive measures to modify existing contracts in the name of maximizing economic welfare and minimizing the burden of sector reform on consumers and on the state.

Drawing on recent country experiences, Woolf and Halpern analyze alternative approaches to restructuring

contracts and designing power markets to reduce rigidities and incentivize IPPs to participate more fully in wholesale power markets and to take on greater market risk. The authors conclude that forced market integration or forced contract negotiation have failed and are counterproductive. Conversely, in countries where IPPs provide a sizable proportion of generation capacity, ignoring market integration may result in insufficient market liquidity and discourage new entry, attenuating the scope for market forces to act for the benefit of consumers. Failure to adapt power purchase contracts and market rules imposes huge resource costs on the economy beyond the financial obligations consumers and taxpayers must bear.

Based on recent experience, a combination of measures, including adaptation of specific market rules, contractual alternatives for enhancing market liquidity, contract buyout provisions, transitional financing mechanisms, and characteristics of the successor entity to the power purchaser, offer promising approaches for reconciling preexisting IPP contracts with new market structures and reducing the magnitude of above-market costs associated with such contracts.

This paper—a joint product of the Water and Sanitation Unit, Energy and Water Department, and the Finance, Private Sector, and Infrastructure Sector Unit, Latin America and the Caribbean Region—is part of a larger effort in the Bank to evaluate and disseminate lessons of experience in designing policies to improve the quality and sustainability of infrastructure services. Copies of the paper are available free from the World Bank, 1818 H Street NW, Washington, DC 20433. Please contact the energy help desk, room F4K-190, telephone 202-473-0652, fax 202-522-3228, email address energyhelpdesk@worldbank.org. Policy Research Working Papers are also posted on the Web at <http://econ.worldbank.org>. The authors may be contacted at fiona.woolf@cmck.com or jhalpern@worldbank.org. November 2001. (37 pages)

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Introduction

There has been considerable activity by both developed and less developed countries to reform their electricity industries. The developed countries are typically motivated by a desire to put a downward pressure on costs and prices whereas the less developed countries often also have the overriding objective of mobilizing investment financing, improving the quantity and quality of service, and extending service to a sizeable proportion of the populace. Both types of countries face a number of common challenges. One of the key issues is how to deal effectively with pre-existing long term contracts, notably, power purchase agreements (PPAs) with independent power producers (IPPs), and their effect on the reform, particularly where wholesale electricity markets are being introduced to enable competitive forces to act for the benefit of consumers.

Only a very few countries that have implemented or are planning power sector restructuring have tried seriously to address the integration or reconciliation of existing IPP contracts with new market structures (notably, the Province of Ontario (Canada), Mexico, the State of Victoria (Australia), California, Thailand, Northern Ireland and Portugal).

This paper discusses:

- policy goals, the means of achieving them through IPP programs and wholesale power markets, and the challenges in integrating existing IPP contracts into new power market arrangements.
- Approaches to reconciling existing IPP contracts with emerging power markets.
- Designing new IPP contracts better to facilitate subsequent integration into electricity markets.

Specific considerations relating to IPP contracts and their impact on power sector reforms include (1) the choice of successor power purchaser or contract holder, and (2) quantifying and recovering above-market costs.

This paper identifies several approaches that can be employed, both singly or in combination, to restructure contracts and design power markets in a manner that reduces rigidities and incentivizes IPPs to participate in wholesale power markets or to enter into contracts under which they accept market risk. The payoff to the country involved is the realization of significant gains in productive and allocative efficiency. If IPPs are not integrated into new markets, the scope for competition will be attenuated, new entry will be deterred, and the country will incur large resource costs if plants are dispatched out of the merit order. The specter of incurring very large economic losses is particularly prominent in smaller economies where a significant proportion of the thermal generating base is comprised of IPPs and where the scope for effective horizontal de-integration and market liquidity is more limited. This issue needs to be addressed rather than avoided and it is encouraging that there are several approaches which can be adopted to achieve a satisfactory outcome.

Background and Context

Objectives of Power Sector Reform Initiatives

A growing number of countries, both developing and developed, have reformed and liberalized their electricity industries by introducing wholesale and, to a lesser degree, retail competition. In developing countries, the principal objective has typically been to mobilize private investment as efficiently and quickly as possible to meet rapid growth in electricity demand and to improve both the efficiency and quality of service. In developed countries, the main goal has been to keep downward pressure on costs and prices as well as increasing efficiency through the capture of competitive market forces. In both contexts, policy makers, investors and industry participants have had to deal with consequences of prior, more partial sector liberalization measures, foremost among these being long term contracts with independent power producers (IPPs).

Approaches to Sector Reform

The 1980s and early 1990s saw two different approaches to reform and liberalization. In the 1980s, the key issue was how to meet forecast demand growth in industrialized as well as developing countries¹. The overriding policy priority was to quickly mobilize funds to build the additional generation capacity. In several countries, there was also a move to diversify ownership or to minimize the use of further public sector funding or borrowing for the purpose. This resulted in a wave of independent power producer (IPP) programs being put in place which lasted well into the 1990s.

In the 1990s the focus shifted somewhat toward realizing greater efficiencies and improving financial viability so that the industry could become economically self-sufficient without placing unnecessary demands on national exchequer or consumers. It was expected that greater efficiencies and a downward pressure on prices could be achieved through the introduction of competition and incentive regulation as well as privatization. This was to result in a reallocation of risks among market participants with the overall goal of incentivizing efficient behaviour.

Countries where there was a serious generating capacity shortfall such as the Philippines, Pakistan, Indonesia and India were not the only countries to pursue IPP programs. A number of Latin American countries (including Chile) encouraged IPP plant to be constructed. Both large and small IPP plant was constructed in the US² and Canada and major project financings of power stations took place across Europe and into Turkey as well as in North Africa.³

¹ Several developed countries forecast demand growth at a level that was never realized, and constructed generating plant (e.g. oil-fired, nuclear) to meet it. They were inevitably left with surplus capacity that gives rise to unrecoverable (stranded) costs when competitive wholesale markets are introduced.

² Both IPP and QF (qualifying facilities built under the US Public Utility Regulatory Policies Act of 1978) plant have been built in the U.S.

³ Although long term IPP contracts may appear incompatible with later, more extensive reforms, viewed with the benefit of hindsight, they may have been justified at the time. They represented a least-disturbance approach with the potential for the quickest potential gains or improvements. There was also considerable private sector enthusiasm for carrying out the projects which, given the lack of prior private sector investment in many of those countries, would not have occurred absent the security of a long-term PPA.

Regulatory innovations in the gas and telecoms sectors, particularly moves to unbundle services, “deregulate” trading arrangements, and introduce competition through third party access to networks, began to influence the thinking on electricity. As a result, attention shifted to reform of the entire sector⁴

Some countries focused on wholesale competition on the basis that generation costs accounted for the largest component of the cost of service to consumers. They tended to choose the single buyer model (typically in smaller or developing countries), a mandatory power pool or a competitive market consisting of bilateral contracts and a centrally organized spot or balancing market. Some countries opted to introduce customer choice or retail competition and have done so on a phased-in approach⁵, while others adopted an “all at once” approach⁶

These reform strategies inevitably raise the question as to the treatment of existing IPP contracts. In developing countries in particular, the lack of creditworthiness of the power purchasers/contract holders (often supported by government guarantees) focused attention on where the money was going to come from to pay the IPPs over the lengthy contract term. As a result, strategic attention was turned to the reform of the power purchaser/contract holder in an effort to improve revenue realization, efficiencies, and quality of service to consumers. This prompted the unbundling and privatization of distribution companies in a number of countries.

These initiatives involved either the creation or overhaul of existing regulatory arrangements. In effect, “de-regulation” has involved “re-regulation”. As a result, it has not simply been central government agencies implementing the reform strategies that have looked at existing IPP contracts. Regulators have also intervened, in some cases in order to uphold the sanctity of contracts⁷ and in others, to force or encourage renegotiation in an effort to promote competition.

The Nature of IPP Contracts

Although the most aggressive of the IPP⁸ programs were put in place in countries where there was significant capacity shortfall, IPPs are also present in countries where there is a capacity surplus. For example, significant numbers of IPPs (and qualifying facilities (QFs) under PURPA⁹) exist in the US. Similarly, there are roughly 100 IPPs in Ontario, Canada. Some of these were the result of legislative or regulatory fiat, designed to encourage the development of smaller plant using renewable fuel sources or to diversify investment and ownership in the sector.

The construction of the IPP plant was usually project financed. The revenue earning ability of the projects was dependent upon a 25/30 year power purchase agreement (PPA), sometimes, but by no means always, awarded via a competitive procurement process. The PPAs were entered into with a single buyer, typically a vertically integrated utility with

⁴ By the entire sector we include generation, transmission, distribution and retail sales.

⁵ Most European countries have chosen to phase in retail competition, starting with giving customer choice to large industrial consumers.

⁶ California and Ontario have chosen to introduce customer choice for all consumers.

⁷ For example, in the US, FERC encouraged integration and renegotiation in the gas industry liberalization but, as a result of criticism of this policy, it upheld sanctity of existing contracts in the electricity industry.

⁸ For the purpose of this paper, an IPP is defined as an independent power producer rather than independent power project.

⁹ The US Public Utility Regulatory Policies Act of 1978

captive retail customers. They reflected a virtual take-or-pay regime¹⁰, built around the expected debt repayment schedule and the requirements of the equity investors, indexed to compensate for inflation. While these contracts now appear to be inflexible it would be a mistake to conclude that they were unnecessary.¹¹

Most of the PPAs that were concluded in the early era of IPP programs were based on a US model which did not reflect the fact that the capacity of the IPP plant might be very significant by comparison to the total capacity on the system and that the power purchaser was, typically, performing two roles, one as the wholesale buyer of energy for sale to retail customers and the other as system operator responsible for maintaining reliability and security of supply. The IPP may or may not have been dispatchable with respect to its energy production but it was usually not required to provide ancillary services or to participate in congestion management measures.

The definition of what constitutes an ancillary service varies around the world. For the purposes of this paper the term refers to those services required by the system operator to maintain system security or reliability. This may include reactive power, frequency control (AGC), certain types of reserve and black start capability. Some PPAs and some Grid Codes or technical rules oblige generators to provide certain services as a matter of course, free of charge. There has however been a trend towards the creation of markets in ancillary services in order to incentivize generators to provide them more efficiently. Despite the payments involved, the overall effect of the market treatment of ancillary services has been to reduce the costs of maintaining system reliability. Paradoxically, where obligations to provide ancillary services are imposed under PPAs, Grid Codes or technical rules without payment, generators will have to comply. As there are few penalties for failing to do so, these mandatory rules have not always proved effective in improving discipline and minimizing costs.¹²

The early 1990s saw the creation of a mechanism for remunerating plant that was dispatchable rather than base load, largely through a two part tariff involving separate capacity and energy payments and more detailed operational rules.¹³ The European PPA

¹⁰ The early PPA contained a single part energy charge. The later PPAs moved to a two part capacity charge (largely covering fixed costs) and energy charge (largely covering variable costs). Although the capacity charge was designed to make IPPs indifferent as to whether their plant was dispatched or not, it was often the case that the energy charge reflected a significant profit which meant that IPPs were keen to ensure that their plant was nevertheless dispatched as base load plant.

¹¹ In the US, prior to the enactment of PURPA in 1978, there was virtually no generating plant which was not owned by a vertically integrated monopoly utility (indeed, the Public Utility Holding Company Act of 1935 made such independent generation virtually impossible). Moreover, the PPAs which resulted were hardly the product of bargaining between equals. Utilities bought power only because they were required to and state regulators often drafted part of the contracts to enforce that obligation.

In addition, the first generation of QFs were financed on a 20/80 equity/debt ratio, which meant lenders required a guaranteed income stream to pay off the debt. In the 1980's when most QFs were under development (but far fewer were operational), every attempt by a utility to avoid its purchase obligation increased the nervousness of lenders and added new inflexibility into financable contracts.

¹² In the 1980s, when a significant number of QFs became operational, there was no separate market for ancillary services; indeed, the purchasing utility itself was required by law to provide ancillary services to the QF, including standby power and black start capability. Many QF contracts did require QFs to provide VAR support, but that product was not unbundled.

¹³ These PPAs may have had even more of a "take or pay" character in that the capacity payments in the new PPAs were clear and explicit. Offtakers had pay for availability regardless of dispatch although the PPAs did have the benefit from the point of view of the offtaker of creating incentives to maximize availability and

became quite sophisticated, incorporating many of the rules and requirements found in the England and Wales Grid Code. These requirements were not inspired by moves towards reform and the introduction of market structures but more to incentivize the IPP to support the purchaser in its system operations role.¹⁴

Many PPAs failed to create clear incentives that resulted in sustained efficiency gains. The consequential effect was increased cost to the whole system in terms of efficiency gain and not simply the loss of specific plant efficiency. In other words, the entire system would bear the cost of the inflexibilities or rigidities created by IPP contracts which would ultimately be paid for by the consumer or the taxpayer.

Problems Created By IPP Contracts in a Market Context

IPP contracts in general, and power purchase agreements (PPAs) in particular, are not easy to reconcile with the introduction of competitive wholesale markets and with the achievement of sustained gains in efficiency.

- (a) The contract terms of PPAs and the associated finance and security arrangements appear, in some cases (usually with the benefit of hindsight), to be expensive¹⁵, and cheaper power on more flexible terms may become available through the market at a later date. In other words they may create stranded costs reflecting their above-market pricing.
- (b) Because the IPPs are protected from market risk¹⁶ by their long-term PPAs they have little incentive to participate in a market. In some countries, their lack of participation would seriously affect the liquidity and indeed the success of the new market in capturing the benefits of market forces, particularly where the size of the IPP plant is a significant proportion of the total plant connected to the system. It is a basic economic principle that there must be an adequate number of buyers and sellers trading sufficient volumes for a market to work effectively.
- (c) Forced contract renegotiation is extremely difficult, because of the legal sanctity and enforceability of the contract terms. The same is true of a non-observance or breach of the IPP contracts by the power purchaser (whether actual or threatened) designed to result in renegotiation. There is an understandable nervousness on the part of governments and host utilities on the one hand (fearing that it would deter further private investment), and IPPs and their investors and lenders (as to the project economics and the other project contract terms which protect their interests) on the other. The process is arduous and lengthy with no certainty as to the outcome.

making the IPP indifferent as to whether it was dispatched or not which was beneficial from the point of view of system operations. Earlier PPAs did not always require the offtaker to buy all energy on offer on a real time basis. (e.g. the QFs in California).

¹⁴ This approach, whilst it may not, of itself, assist in integrating IPP contracts into new markets, will reduce, to some extent, the difficulties of operating the IPP plant alongside new market structures and could reduce some of the stranded operating costs.

¹⁵ There may have been a lack of competition at the bidding stage or an even-handed negotiation process may have been absent.

¹⁶ Market risk essentially means the risk associated with participating or trading in a market, notably finding willing buyers for all (or a significant proportion) of the output of the plant at prices that are not so volatile that the market participant is unable to earn a reasonable, predictable return.

- (d) In the early stages of any new wholesale market, prices and the extent of market risk will be difficult to predict, quantify and mitigate. There will always be an initial period for the market to settle down and market rules will change to reflect operational experience. During this period, IPPs would prefer the certainty of the power purchase agreements.

In short, the main problem areas with IPP contracts are:-

- their relatively long duration;
- the fixed prices which are designed to create a stable and certain revenue stream for the IPP;
- lack of requirement for the IPP to assume any market risk;
- contract provisions that are less demanding than detailed market rules which are designed to promote increased efficiency and competition

For these reasons, it has proven difficult to find simple mechanisms to integrate IPP contracts and plant into new wholesale electricity markets.

A summary of country experience with integrating IPP contracts is set forth briefly in Annex 1. Only a few countries have made a serious attempt to grapple with the problem of integrating IPP plant into new market. These include Victoria, Thailand, Mexico, Guatemala, Ontario, Northern Ireland, Portugal and Poland. Of these, only the reforms in Victoria, Ontario, Northern Ireland, and Portugal have so far been implemented. The rest are still under discussion or are in the run-up to market opening. The countries which have had notable IPP programs such as the Philippines, Hungary¹⁷, Indonesia, Pakistan, Turkey, the Dominican Republic have not yet undertaken or are only now commencing a full reform involving restructuring and market implementation. In some other cases, the capacity represented by the IPP plant may have been too small to be of significant concern from the point of view of market liquidity or stranded costs.

Potential Impact of the Power Market Development on the IPP

The design of power markets is driven by the desire to capture the benefits of competition for the consumer by increasing operating and plant efficiency and distributing those gains to users of the system. For markets to work in an efficient manner, they must be stable and achieve certainty of outcome without creating opportunities for market power abuse and gaming. The market rules have almost invariably failed to consider the special position of IPPs, except by way of exemption from the general rule in the case of small plant. This is because the market rules are usually written to reflect a theoretical design (created in the absence of operational experience with existing plant) with the objective of creating a marketplace in which efficient plant competes effectively to create a downward pressure on prices.

¹⁷ The Hungarian government has announced its intention to de-regulate the electricity industry and to restructure the state-owned utility, MVM. IPPs have protested and maintained that a government-backed decision by MVM in 1999 not to sign more long term power purchase agreements has crippled investment plans. IPP developers maintained that they have sunk considerable amounts in planning new power stations which they stand to lose if the PPAs that have been signed are not honored. They maintained that it will not be possible for the government to capture the benefits of introducing competition for the consumer because of the existing low price of electricity.

Under the time deadlines and political pressures which accompany sectoral reform decision making processes, it may have been thought too difficult or undesirable to factor in the operational or economic difficulties of existing plant. Choosing the lowest common denominator by reference to the capabilities of existing plant or risk allocation under existing contracts would not achieve the desired efficiency gain. The market rule designers may also have been deterred from grappling with the issues because of the perceived legal sanctity of the IPP contracts.

It has been a feature of market design exercises that instead of attempting to integrate IPPs, the outcome has increased the difficulty of integration and magnified the stranded costs, diminishing the potential gain to be derived from the existing IPPs on the system. As a result, the realization of this potential gain to the consumer, derived from competition when all market participants take full market risk, is likely to be delayed over a relatively lengthy transition period or may never be fully realized.

The impact that the design of the wholesale market will have on the IPP contracts and their potential for integration into the market will depend upon the objectives of the new market and the terms and conditions of the power purchase agreements. The key criteria in market design decisions are transparency, fairness, and predictability. The adoption of an explicit set of technical rules, for example a Grid Code, often designed to improve system security and reliability may further widen the gap between the scope of obligations of the PPA and the requirements of the new market.

Because they are designed for a different purpose, the market arrangements in most countries will likely require IPPs to follow rules (typically much more detailed and demanding¹⁸) which are not contained in their PPAs. This can create significant additional costs for the IPPs which they may have no means of funding. Annex 2 illustrates the divergence in PPA and market rule obligations. Examples of market obligations include provision of ancillary services and congestion management services to maintain reliability, compliance with market rules with respect to scheduling, dispatch, 24 hour staffing, communications facilities, settlement, billings, metering etc.

It is also true that market rules usually provide real cashflow to market participants to the extent that they comply with them. In contrast, obligations imposed by a Grid Code or technical rules are often not remunerated or require flexibilities or performance to which the IPPs are unaccustomed (e.g. security constrained dispatch). The bifurcation of responsibilities between system operators and market administrators/operators may also add to the differences between the old and new worlds.

The risk allocation and contractual protections associated with IPP projects are likely to render IPPs and their project agreement counter parties unable or unwilling to relinquish the protection of their project agreements and to take market risk in a market that has not yet settled down. IPPs will be influenced by their project lenders, investors, fuel suppliers and possibly steam off-takers with which they have entered into long term contracts. Their ability to perform under those contracts will be crucial to all these parties. Once the project debt has been paid and the investors have received a reasonable return on their investment, the IPP may be more amenable to participate in the wholesale market,

¹⁸ See "Adaptation of Market Rules" below for further details

particularly if its plant is efficient and it is able to compete and minimize the likelihood of above-market costs.¹⁹

The price of capacity and energy under long term IPP contracts may prove to be significantly higher than the prices in the wholesale market. If the market is well designed and effectively captures the benefits of market forces, plant should become more efficient and more flexible with the result that prices will tend to decline (in real terms). However, IPP contracts rarely contain incentives to improve efficiency over time. The power purchaser will only be able to re-sell the power at the prevailing market price. The question then arises as to who should bear the above market costs-- the power purchaser, taxpayers or consumers. Typically consumers foot the bill on the argument that it is for their benefit that the new market has been introduced.

Potential Impact on the Power Purchaser

In the course of sector restructuring, the entity to which the IPP contracted to sell power will be reorganized according to the basic functions of generation, transmission, system/market operations, distribution and retail sales. It (or each of its successor companies) will usually be a full market participant carrying out one or more of these functions. It might become a company designed to hold residual liabilities or handle stranded cost-recovery, as was the case in Ontario. It may still be required to comply with the market rules. IPP contracts can expose contract holders (i.e. power purchasers) to a number of new risks following the introduction of a competitive market. The difference in the price payable to the IPP under the PPA and the prices at which power is sold and bought in the new wholesale market exposes the power purchaser/contract holder to significant financial risk in the form of stranded costs. In addition, inadequate or no scheduling and dispatch rights under the contract (which were a feature of the first generation of PPAs) may:

- (i) prevent contract holders from taking advantage of profitable opportunities to use the plant to provide ancillary services;
- (ii) expose the contract holder/power purchaser to claims for damages by the IPP in the event that the IPP is not paid if the plant is not dispatched pursuant to the market rules and it earns less than it would have done if it had been dispatched²⁰;
- (iii) make it difficult for the contract holder/power purchaser to comply strictly with the new market rules which will be binding on it if, for example, it has no contractual right to obtain certain information that the rules require to be provided to the system operator (ISO) (e.g. notice of impending trip or change in operational capability which might result in the contract holder having to make payments under the market rules for resulting imbalances) or cannot instruct the IPP to follow market rules e.g. with respect to dispatch, the provision of ancillary services or transmission congestion management measures.

¹⁹ There is evidence of this emerging in Poland despite the fact that it is by no means certain that IPPs will be allowed to recover the full amount of their above-market costs

²⁰ The power purchaser may have been able to schedule and dispatch and to order plant off the system in an emergency but, under the older PPAs, it would have had to pay an energy charge for power not taken. Under the later PPAs it would have paid a capacity charge to the IPP.

Incidence of Above-Market Costs

As noted above, a major risk is that the price of capacity and energy under long term IPP contracts may prove to be significantly higher than the prices in the wholesale market. If the quantity of power purchased from an IPP is small and the power purchaser is a distributor or retailer to captive end-consumers, the regulator could allow the distributor to pass the purchase costs on to the end-consumers, in which case the above-market costs will be hidden or blended with the cost of other purchases in the wholesale market. If the contract holder/power purchaser is not able to pass the costs on to consumers in this way (e.g. because the regulator does not allow it or because the consumers are customers with the option of purchasing from other retailers), the above-market or stranded²¹ costs will be apparent. In this case, it will be able to resell the power only at the prevailing market price.

The question then arises as to who should bear the above-market costs. Should they rest with the power purchaser/contract holder, which (depending upon what its functions have become as a result of the restructuring) may be in a poor position to manage or mitigate them? Should the power purchaser/contract holder be compensated in some form for having inherited PPAs which at one time appeared to be economic but are no longer so because of the introduction of the new market?

The choice as to who should bear the above market costs lies between:-

- the power purchaser/contract holder, or rather, its shareholders which may be in the public or private sector;
- the tax payers at large, on the basis that power sector reform is in the public interest; and
- the consumers of electricity, on the basis that they are the ultimate direct beneficiaries of the reforms and because their electricity bills provide a relatively simple mechanism for raising a levy to realize revenues to fund the above-market costs.

Most governments that have addressed the issue have decided that, as a matter of policy, the shareholders should not bear the burden, particularly if private sector investors are involved, and that the consumers, who should most directly benefit from the reforms, should contribute to the funding of what is essentially a cost of transition to the benefits of competition which they will ultimately enjoy.²² This policy is usually driven by a concern on the part of government that using public or taxpayer funds will provoke criticism as well as jurisdictional and political issues. There is also the fear that using shareholder or successor company funds will deter investment and undermine the financial viability of the successor company. Quantifying and recovering above-market costs is discussed in more detail below.

The Meaning of "Sanctity" of the IPP Contracts

In the context of the impending introduction of competitive electricity markets, IPPs may take the position that every word in their contracts is sacrosanct. Faced with the threat that

²¹ These costs are stranded because there is no means in the marketplace to recover them. They are called above-market costs to distinguish them from other types of stranded cost.

²² Indeed, in California and Ontario the above-market or stranded cost levy on consumers was termed a "competition transition charge".

the economic bargain reflected in their contracts may not be honored to the letter, this stance is understandable. However, a strict interpretation of any contract is not supported in many jurisdictions if damages which result from a more relaxed interpretation are non-existent or de minimis, if they cannot be quantified, or are too remote.

Remoteness of damage or loss is a legal concept that will not allow claims for damages that were not within the contemplation of the parties when the contract was entered into. In some cases the courts may only allow the recovery of sunk costs but PPAs are essentially agreements guaranteeing a revenue stream over the duration of the contract. In this case, the magnitude of future earnings is usually in the contemplation of the parties which would give rise to damages for loss of future earnings. Indeed, some of the later PPAs provide a formula for calculating the net present value of these revenues which would be payable in the event of breach, termination or buyout.

In contrast, orders for specific or exact performance of contract terms are difficult to obtain. Typically, they will only be available if damages are not an appropriate remedy, which they usually are. Civil law tends to respect the economic balance between the contracting parties as opposed to the strict letter of the contract. In short, courts tend not to take an approach that ensures perfect performance of every detail of the contract terms if damages are an appropriate remedy. This appears to be a doctrine of the contract law of many developed countries.

Moreover, guarantees of the power purchaser's obligations will not require actual performance of the detailed contract terms either. They will usually only guarantee payments under the PPA. This means that the IPPs cannot rely upon the guarantee to ensure that the contracts are complied with strictly, for example, in relation to details which are important from an operational standpoint. They may be able to rely on them to cover payment defaults but probably only after considerable delay and possibly litigation.

The Government of Ontario initially issued a statement that the sanctity of existing contracts would be preserved, but subsequently clarified that it did not mean that each contract term, however minor, should remain intact. The thrust of the approach was that the IPP contracts should continue to maintain the commercial bargain between the parties, but subject to that, the IPPs should expect to comply with the market rules.

Approaches to Integrating IPPs into Power Markets

Integrating IPPs into new markets created as a result of power sector restructuring holds the promise of benefiting consumers through increased competition, liquidity and hence efficiency. The objective is to do so in a manner which minimizes above-market costs while protecting the IPP economics during the transition.

Integrating IPPs into wholesale market arrangements will require modification of at least some of the following: market rules, IPP contract terms, identity and powers of the contract holder, contract management arrangements, and mechanisms for funding above-market costs associated with the IPP contracts. The challenge is to do so in a manner which incentivizes IPP integration without unduly compromising market efficiency nor system reliability.

There are several potential approaches to addressing the difficulties discussed in the prior section. These approaches incorporate different combinations of policy measures and can be characterized as follows:

- forced market integration
- forced contract negotiation
- integration by adaptation of market rules
- virtual generation/managed contracts
- voluntary renegotiation
- contract buyout.

Figure 1 shows policy measures associated with various integration options. The following section discusses the salient features of each option. Their applicability to specific country circumstances will depend on the proportion of IPP plant to total generating capacity, the degree of surplus generation capacity, the goals and design of the sector reform program itself, and overall economic conditions existent in a given country.

Figure 1

Policy Measures for Dealing with IPPs

Approach	Policy Measures			
Name	Change Market Rules	Change Contract Terms	Change Contract Holder/Manager	Change Funding Arrangements
1. Forced market integration (by legislation)				
2. Integration by adaptation of market rules	✓			
3. Forced renegotiation		✓		
4. Virtual generation/managed contract			✓	
5. Financially facilitated market integration				✓
6. Contract buyout		✓	✓	
7. Fully facilitated market integration	✓			✓
8. Facilitated voluntary renegotiation or buyout	✓	✓	✓	

The four policy measures described in Figure 1 give rise to six main approaches which are described more fully below. These approaches are meant to achieve several goals:-

- increase market liquidity, efficiency and competitiveness;
- reduce above-market costs;
- enhance system reliability;
- increase plant efficiency;
- improve grid and market discipline.

Forced Market Integration

IPPs could be required by legislation to become market participants where the legislation simply applied to all generators equally without considering existing contract terms between the IPP and off taker. In Guatemala, this approach did not, in fact achieve any

significant result. The IPPs essentially ignored the legislative requirements and rested on their contract rights.

This approach leaves the IPP with two difficult choices, it can:

- (a) seek damages for constructive termination²³ of the PPA. The scope for this may be limited by the terms of the PPA and/or by the general law which may limit damages to losses actually arising and may in any event not permit the IPP to recover foregone profits; or
- (b) agree to become a full market participant selling its power through the new market on behalf of the power purchaser/contract holder, and attempt to negotiate a position under which the power purchaser/contract holder makes good any shortfall between the contract price and the actual market price received by the IPP under the market rules.

This is a high risk approach for a government to pursue. If it is perceived as forcing a constructive breach or termination of the PPA by use of its legislative powers, it could be accused of a form of expropriation without compensation and would find itself in litigation or arbitration on both constitutional and contract grounds. It would significantly damage its reputation with its own private sector and with international financiers.

Forced Contract Renegotiation

Another interventionist approach is when government forces renegotiation of the IPP contracts so that they not only become compatible with the technical and trading rules of the new market but also require the IPPs to be active market participants taking full (or at least partial) market risk. This clearly suffers from some of the same difficulties of the forced integration approach outlined in the previous section.

Forced renegotiation of PPAs would likely meet with hostility from the international investment community. If the experience in Pakistan²⁴ and Northern Ireland is anything to go by, not only does it involve immense effort and expense, it may produce relatively small results for the contract holder/power purchaser. Only if the outcome of the renegotiation could be predicted to achieve a result that is both fair and satisfactory to both parties would it be worth undertaking. However, the risk of the government undermining its credibility and its ability to attract investment in the future would be significant. The difference is that negotiation by definition is not a unilateral action over which governments can simply exert their legislative authority. Unilateral action to change contract terms could amount to expropriation of rights as well as breach of contract.

Governments may contemplate a threatened or actual breach by the contract holder/power purchaser of the PPAs in order to bring about the renegotiation. Economic, as distinct from legal argumentation has at times been advanced that non-observance or breach of an agreement could be an efficient course of action if it proves to be more

²³ Constructive termination means that although there was no formal termination by one party to the PPA, the actions of that party lead to no other conclusion than the party intended to and, in fact, did terminate it.

²⁴ The attempts to renegotiate IPP contracts in Pakistan were not primarily driven by the desire to integrate them into a potential new market.

economic than to comply with the contract to the letter.²⁵ While this notion can find a conceptual basis in neoclassical welfare economics and game theory, it is obviously unlikely to engender a great deal of sympathy or co-operation on the part of the IPP and will lead to the same problem as any other form of forced renegotiation.

Ultimately, the legal system sets the framework or fallback for renegotiation, particularly if breach or non-compliance with the PPA is threatened or actually takes place. Pursuing claims through litigation or arbitration invariably creates considerable uncertainty, delay and expense for all parties. If both parties feel that they have strong cases, they will be placed in a position of considerable reliance on the agreed dispute resolution process which, however developed and sophisticated, is likely to create uncertainty as to its outcome. It may act as a disincentive rather than an incentive to reach agreement. Moreover, dispute resolution processes never create the kind of negotiating chips that the parties think ought to be available. The issues involved in integrating IPP contracts into markets have not been addressed through one of these processes and it is not clear whether a court or an arbitrator would take a narrow view of the issues in dispute or a broader view considering the public policy issues involved in the whole reform process. Therefore, reliance on dispute resolution processes rather than regulatory processes may prove to be clumsy, slow, costly, and of uncertain outcome.

An alternative approach to facilitating the initiation of renegotiations is for the Government to invoke the “change of law” clause under PPA. These clauses which appear in most PPAs, entitle the IPP payments to cover increased costs brought about by a change of law. Since markets are often introduced through new legislation, the contract holder/power purchaser could use the clause to call all IPPs to the negotiating table on the same basis, in order to discuss consequences of the change of law.

In order to maintain investor confidence and credibility, this process would have to be extremely fair and transparent and treat all IPPs in the same manner. This could produce difficulties if the PPAs and plant are very different. One unit might simply not physically be able to comply with a particular contract term or market rule (because of its design) whereas another unit would readily be able to do so.

One instrument which may be considered in inducing IPPs to participate in the new market is to require conversion of a power purchase agreement into its financial equivalent, a so-called “contract for differences” (CfD),²⁶ which would hedge the uncertainties surrounding prices in the new market. Contracts for differences are financial hedging instruments which are also derivatives.

They are usually cast as put and call option contracts to pay the difference between the market price and the agreed strike price. Although no physical commodity sale is involved, they can be quite complex and detailed with the terms “sculpted” to reflect the physical properties of the generating plant in question. Risks, including the basic operations and maintenance risks are often more precisely defined and allocated than would be the case in a traditional PPA. Force majeure relief may be limited or not be allowed at all.

²⁵ Optimal breach of contract might be construed as preferable to rigid enforcement of original conditions of a contract if the cost of performing exceeds the cost to the other party of not performing. This begs the question as to whether legal remedies for breach are designed to promote informal renegotiation.

²⁶ A contract for differences is a financial hedge which provides purchasers and sellers the option to replace the spot market with a fixed price.

In order for counter-parties to take positions in a CfD, two elements are required. First, there needs to be a publicly available and economically meaningful reference price for spot power. This requires a transparent and stable wholesale market. Second, in order for the CfDs to be liquid (i.e., transferable to third parties and of uniform terms and conditions), the country needs to have laws permitting these transactions²⁷. Therefore, this option can only really be put in place in the latter stages of the sector restructuring as it follows market structure and design of market rules.

Another alternative is to put in place a simple mechanism designed to track the difference between the amount of money that the IPP would have received in the market and the amount that it would have been paid under its PPA. The PPA could be rewritten to require the IPP to participate in the market in accordance with the market rules and for the contract holder to pay the difference. This should produce a satisfactory outcome for the IPP, its lenders and investors. However, it begs the question as to how the difference would be funded and when and if the IPP would take on similar market risks as other participants.

While the government or regulator which forced the renegotiation could make it clear at the outset of the process that a satisfactory outcome for the IPP would be assured, this would be unlikely to incentivize the IPP to adopt anything other than a passive approach at the negotiating table. It would certainly not be incentivized to find innovative solutions designed to ease integration, maximize the effectiveness of the new competitive marketplace or to minimize above-market costs. Encouraging the IPP to put forward solutions will be very useful, as it will best understand the capabilities of its own plant as well as the opportunities the new market may present. It should also be well placed to provide input into the design of the market rules to ease integration. This is the reason that the voluntary renegotiation approach referred to below may have better prospects for producing positive outcomes.

Voluntary Renegotiation

It is not out of the realm of the possible to create markets that present such attractive opportunities that IPPs are prepared to renegotiate their contracts voluntarily so that they can participate at least to some degree in the market. Just as all markets have distinctive characteristics, so too do IPPs. The ideal solution needs to be thought through on a case-by-case basis. Innovative ideas may provide the best answers from all perspectives. For this reason, if it can be achieved, a voluntary, rather than a forced approach to renegotiation is preferable. In order to bring the IPPs to the negotiating table in circumstances that are likely to achieve efficient and tractable solutions from all perspectives, it is useful to look for incentives that will assist both parties.

If the PPA can be renegotiated on a basis that integrates the IPP into the market to some extent, for example, by allowing the IPP to sell any uncontracted capacity²⁸ or ancillary services into the market and earn more revenues which it could share with the power purchaser, the IPP will give up nothing and will gain. The power purchaser will also

²⁷ Even in the US, the legal and regulatory framework is quite restrictive.

²⁸ A note of caution, however, disputes have arisen in Portugal and Ontario as to whether the uncontracted capacity belongs to the IPP or to the power purchaser. Typically the agreement will provide that all of the capacity and energy output of the plant must be sold to the power purchaser but at the same time it will only be required to purchase a specified amount. The legal position in this circumstance tends to be unclear.

benefit because it will reduce its above-market costs and its exposure under the market rules with which it must comply. The IPP could even be asked to share some of its additional revenues with the contract holder/power purchaser. Consumers will benefit from a more liquid market and a lower stranded cost levy.

In their article "Contracts and the Institutional Environment for Electricity Reform", Albert L. Danielson, Nainish K. Gupta and Peter G. Klein ²⁹ quote examples of successful renegotiations of NUG contracts ³⁰, arguing that this approach can generate gains for all parties and should not be discouraged by regulators or the courts in upholding existing contracts. They quote the case of Citizens Power which successfully restructured some NUG contracts through a combination of physical and financial engineering that maintained economic value for NUG while generating substantial savings for the utility. The outcome of the restructuring of the contracts included:-

- transferring certain risks to the utility to minimize the cost of funds;
- lowering levels of power flow at above-market prices to the utility;
- extending the contract duration by 5 years at a price consistent with market price projections;
- dividing the single energy price into an energy and a capacity component³¹.

There are other slightly more aggressive methods of renegotiating PPAs on a voluntary basis. In California, purchasers took a "firm but fair" approach to contract administration. If a power producer wanted to change any element of a PPA (size, location, fuel type, etc.), the purchaser would attempt to restructure the financial terms in return. The purchaser typically desired greater curtailment rights, capacity and energy price reductions, and shortening the duration of the PPA (this was possible because typically the capital costs of the project are usually paid off in less than half the length of the typical 25-30 year PPA term). Other changes included levelizing payments to avoid front loading.

A purchaser would still negotiate to pay for dispatchability or a shorter term once a plant was operating. This required a valuation of these attributes from the perspective of the purchaser, which the regulator often rejected. Since the renegotiations were predicated on regulatory approval (so that the costs could be passed through to customers), these bilateral negotiations had an invisible third party at the table in the form of the regulator. Regulators are not always well equipped to take a commercial view of the value of contract attributes. For the most part, they would do better to rely on the economic incentives of the contract parties to reach the right deal.

Another variant is to restructure the PPA as a tolling arrangement to mitigate market risk. A tolling agreement can be put in place between the IPP and an entity that both supplies fuel and sells the output of the power plant. This provides a hedge between the cost of the fuel and the price of the power sold. The payment regime could be structured to cover some or all of the debt service.

²⁹ Electricity Journal December 1999 pages 51-60, Elsevier Science Inc.

³⁰ "NUG" refers to non-utility generation which is independent of investor-owned utilities. It is, therefore, equivalent to IPP plant.

³¹ A two part price should be more cost-reflective and ensure that the IPPs fixed costs are paid if the plant is available.

Contract Renegotiation Facilitation Process

Several governments and regulators have sought to establish a contract renegotiation facilitation process.³² Certainly, consulting IPPs about intended restructurings or reforms would be helpful, if only to assist in calming fears of the unknown and establishing credibility for the process. The “change in law” clause commonly found in PPAs (which indemnifies IPPs from any additional costs) could be used to invite IPPs to the negotiating table on a neutral basis.

There remains the risk that a facilitation process could be perceived as leading to forced renegotiation. Accordingly, it would have to be established on a basis that was extremely fair and transparent. It would be necessary for government to give assurances that the outcome would not disadvantage the IPP³³. If an independent regulator has been set up, it might be preferable to allow the regulatory body to conduct the process to reduce the scope for politicization. In developing countries, where the legal and regulatory framework is often not well developed nor tested, investors and lenders may well be nervous about relying on the contract terms and the ability of the courts to enforce them against public sector contract holders and guarantors.

The type of contract renegotiation facilitation process in Ontario involved an independent team of advisers establishing a menu of possible amendments and solutions as a basis for discussion and to provoke further ideas. This approach was particularly beneficial in relation to the treatment of consequential amendments to the PPAs, which were brought about as a result of the restructuring of the contract holder/power purchaser into successor companies and to deal with certain other aspects that needed change (e.g. price inflation indices which no longer existed).

In Ontario and Thailand, a contract manager was appointed who was financially incentivized to seek mutually beneficial solutions to facilitate voluntary renegotiation. This could be facilitated by the government or the regulator setting up a process to encourage rather than coerce the parties to determine if a suitable adaptation of the PPA could be agreed upon that would ease integration and/or minimize above-market costs. For example, a contract manager could be given a percentage of the above-market costs that were avoided as a result of the outcome of the re-negotiation or could be given a fixed or variable bonus (within a cap and collar) for finding and achieving the implementation of a solution to which the parties had agreed.

Adaptation of Market Rules

As explained above, there is likely to be a significant gap between the operating provisions of the PPA and the technical and commercial rules of the new market. It may be possible to facilitate integration into the market by designing or modifying the rules to minimize the gap.

Market rules are considerably more detailed than that of even the latest and most sophisticated PPAs. The market rules are meant to achieve three principal goals: (1) create a legally enforceable set of procedures for a complex set of trading arrangements, both on a forward and real time basis, that is certain and auditable (2) provide incentives to improve

³² e.g. Pakistan, Guatemala, Ontario, Northern Ireland.

³³ The assurance should be given in a manner that would deter the government or regulator from renegeing on it.

reliability, plant performance, and flexibility, as well as grid and market discipline, and (3) ensure non-discriminatory access to transmission and distribution systems. In contrast, the PPA is designed primarily to ensure that the contract holder/power purchaser receives the capacity and energy for which it has contracted and that the IPP is paid for it. In the later, PPAs, the IPP may also be required to support the power purchaser in its role as system operator. Market rules therefore imply additional obligations for the IPP which carry additional costs for which there is no machinery in the pricing formulae or in the contract terms allowing for reimbursement under the PPA.³⁴

The size of the gap also depends upon the degree of complexity and the objectives of the market design, particularly if there are detailed, market-based rules relating to balancing, ancillary services, and congestion management. In developing countries these rules may not be at all sophisticated but are necessary in order to foster grid discipline. How these rules are formulated places different risks on each of the market participants and requires them to learn new commercial skills with respect to trading in parallel competitive markets³⁵. IPPs may well not have the managerial nor financial capacity to do so, particularly if they are project financed. Moreover, prudential requirements are imposed on market participants under market rules to protect against payment default. IPPs, like all other market participants would need to have access to funding to make deposits, financial guarantees or a substantial credit rating which typically they may not have if they are project financed.

Sector restructuring models which require a mandatory pool or power exchange may preclude bilateral contracts that could otherwise allow an IPP to adopt the so called “anchor tenant approach”. This would enable part of the IPP plant output to be sold directly to an industrial consumer, for example, under a long term contract with the balance being traded in the competitive wholesale market. In this way the IPP could hedge much of the market risk. This is particularly suitable for co-generation facilities where revenues from sales of steam are used to underpin the financing. However, revenues from these sources are usually not sufficient to cover all of the debt service but if the power plant has a relatively low cost position, there can be a high degree of confidence that revenues from trading in the market will be satisfactory. On the other hand, some governments and regulators are reluctant to allow this approach because it will allow new IPPs to cherry pick the best industrial customers and keep those customers out of the new market, which may affect liquidity on the demand side.

If addressed early in the sector restructuring process, the market rules could be designed to attract new entrants where new generating capacity is urgently needed, and also to motivate existing IPPs to voluntarily participate in the new market. At its most basic level, the market rules could be adapted to minimize the administrative costs of participating in the market (eg. requiring new communications facilities or 24 hour/7 days per week manning requirements which add cost).

³⁴ PPAs do usually allow for claims to be made for reimbursement of increased costs caused by a change in law or change in tax. Arguably, if the government were to use new legislation to force market integration, IPPs could make a claim under these contractual protections for any increased costs that they incurred.

³⁵ Parallel or separate competitive markets exist in a number of jurisdictions, particularly where ancillary services are purchased and paid for separately. There may be separate or parallel markets in energy (e.g. a bilateral contract market, a day-ahead market, an on-the-day market, a real time or balancing market), in ancillary services and in congestion management measures. Market participants will have considerable freedom of choice as to which markets they trade in, the prices and services they offer and the period of their commitments.

Often market rules contain exemptions for small plant, which could be extended to existing IPPs on a transitional basis. These include requirements to submit schedules and certain operating information and in the case of the smallest plant, to follow dispatch instructions and provide ancillary services. However, the dilemma is whether these exemptions will compromise the efficiency of the market (particularly the new basis for economic dispatch). Another option is to include a transitional capacity payment in the market rules to encourage IPPs to participate and take market risk. Thus far no jurisdiction has made a significant attempt to follow this approach.

A summary of the gap between typical PPA provisions and market rules is set out in Annex 2. Minimizing the gap will certainly make life easier for the ISO and the power purchaser/contract holder and may reduce above-market costs.

Virtual Generation/Managed PPA

In the course of sector restructuring, the PPAs are transferred or assigned to a successor entity to the original power purchaser/contract holder. The successor may be government-owned or private. There is obviously a choice of successor company resulting from a typical restructuring and this choice usually lies between another generator or a distributor and/or retailer. Such an entity will typically be a full market participant able to sell or resell the power produced by the IPP into the market, preferably with a mandate to minimize above-market costs.

A distinction can be drawn between two roles of the power purchaser/contract holder, that of a contract party under the PPA and that of contract manager, carrying out the day-to-day administration of the contract terms and the performance of the contract holder's obligations. It is possible to appoint a separate contract manager as a surrogate or agent for the power purchaser/contract holder to carry out certain functions under that contract with a view to achieving specific objectives, notably to maximize the proceeds of sale so that the above-market costs are reduced.

The distinction between the role of contract holder and contract manager is derived from an analysis of the functions of the power purchaser under the PPA. The contract holder carries out the functions of the party to the contract e.g. dealing with funding, contract amendments or buy-out. The contract manager, on the other hand, is responsible for the day-to-day administration of the PPA and the operational relationships with the IPP and the ISO. It can more easily participate in the market to resell the IPPs contracted capacity and energy.

The benefits to this approach include:

- (a) existing contractual rights of the IPPs are preserved;
- (b) need for change to the PPAs is minimized - it requires least – disturbance, if a decision is made at an early stage to adopt this approach ; and
- (c) the contract manager focuses on bidding the output of the contracted capacity into the competitive market as if the plant belonged to the contract manager itself - hence the name “virtual generation”.

In Victoria, Australia, the contract manager is called the PPA Trader. The existing PPAs were assigned to one of four PPA Traders, each licensed to administer one of the PPAs as

a “virtual generator” as if it owned the contracted capacity and energy. They purchased the energy pursuant to the PPAs and sold it into the electricity pool. The loss they sustained was fed back into the market as a levy against all market participants. This levy was then passed through to customers. In this case the contract managers were not incentivized to minimize above-market costs.

A variant of this is applicable in the context of a restructuring and privatization. A PPA may be assigned to a successor company with a portfolio of generating plant. It could bid the output of the IPP plant into the market along with the output of its other plant.³⁶ Owning or managing a portfolio of generating plant in a competitive market has certain advantages over the ownership of or rights to a single plant as the pooling of assets permits greater flexibilities in their optimization. The above-market costs of the IPP would be reflected in a reduction in the acquisition price of the assets to reflect the above-market costs of the PPA, which form part of the portfolio. In this instance, the Treasury/tax payer bears the cost. If cost pass-through is permitted, then the assets are valued upward accordingly with a corresponding increase in acquisition price. In this instance, consumers bear the cost in proportion to the degree of cost pass-through

Contract Buyout

The government may arrange the buyout of IPP contracts either by the contract holder/power purchaser or by third parties. Termination or buyout of the contract in this way would require the consent of the IPP’s lenders, bond holders, and possibly equity investors. They would be unlikely to consent unless a buyout price is paid that will cover outstanding debt and the present value of the revenue-earning potential of the investors and bond holders. While some of the more recent PPAs do contemplate contract buyout, many of the earlier PPAs have no machinery for this and a buyout price would have to be negotiated.

If the contract holder/power purchaser were to buy the contract out, the likely result could be the purchase of the IPP plant itself with which the new contract holder would then participate in the new market, taking full market risk. If the power purchaser/contract holder is not able to raise funding to buy out the contract, an alternative would be to arrange for buyouts by third parties through an auction process. Bidders could be required to purchase the contracts (or even the IPP plant) on the basis that they would take full market risk. The question then arises as to whether third party, private sector contract buyers would substantially discount the buyout price that they were prepared to bid to reflect uncertainties associated with the new market.

The Ministry of Finance in Ontario took preliminary steps to initiate an auction process for third party contract buyouts, which it later abandoned. It was felt that contract buyers might be difficult to find and would substantially discount the prices that they were prepared to bid due to uncertainties of the new market. The Ontario government was initially attracted to the prospect of crystallizing above-market costs at an early stage through a competitive tender process rather than running the risk that these costs would continue to be incurred for the 25-40 year terms of the PPAs. It later realized that it would have to fund any difference between the buyout price that third parties were prepared to offer and the price that would fully compensate the IPPs. The auction process may take place at a later date once the market has settled down. In the meantime, the plan is to appoint suitably experienced contract managers incentivized both to minimize above-

³⁶This approach was at one point proposed for the Philippines.

market costs and to attract the IPPs to voluntarily renegotiate their contracts to achieve partial market integration.

Comparing the Approaches

Figure 2 compares alternative approaches to integrating IPPs into wholesale power markets according to five evaluation criteria that have formed the basis of the foregoing discussion

Figure 2

Approaches to Integrating IPPs into Power Markets

Evaluation Criteria	Forced Market Integration	Forced Renegotiation	Market Rules Modification	Virtual generation/ Managed PPA	Voluntary Renegotiation	Contract Buyout
1. May adversely affect credibility of Government	Yes	Yes	No	No	No, if process transparent and fair	Yes, unless IPP compensation is fair
2. May deter future investors	Yes	Yes	No	No	No, if process transparent and fair.	No, if IPP compensation is fair
3. May adversely affect IPPs economic position reflected in PPA.	Yes	Yes	Yes unless exemptions are granted.	No	No (IPP unlikely to agree to any deterioration)	Yes unless IPP is fully compensated.
4. May reduce impact on consumers of above-market costs.	Yes	Yes (depends on outcome)	Unlikely	Yes, if an effort is made to reduce above-market costs.	Yes (depends on outcome)	No, unless buyout price offered by third party is discounted to reflect market uncertainties.
5. May adversely affect efficiency or competitiveness of new electricity market place.	No	No (depends on outcome)	Yes (but it may be transitional)	No	Maybe (depends on outcome)	No

In summary:

- The forced market integration and forced renegotiation approaches have been attempted but are very unlikely to achieve a satisfactory outcome from the point of view of IPPs or consumers.
- The adaptation of the market rules, on a transitional or exempting basis could, in some circumstances prove successful provided that the market could still work efficiently and competitively with respect to other generating plant.
- The virtual/managed PPA approach could be a useful technique provided that the contract manager is incentivized to minimize above-market costs.
- Voluntary renegotiation stands a much better chance of succeeding than forced renegotiation if there is innovative thinking to find mutually beneficial solutions.
- Contract buyout has the advantage of crystallizing above-market costs at an early stage, but inexperience with the new market and the likelihood of having to make mid course adjustments to market rules may result in contract bidders demanding a “new market risk premium” which will magnify above-market costs.

These approaches are not mutually exclusive but rather may be used in combination. One combination that appears to have good prospects for delivering successful outcomes is the adaptation of market rules coupled with a change of contract manager and voluntary renegotiation.

Designing New IPP Contracts

It is not the case that IPP contracts and new power markets must be viewed as mutually exclusive and that once the move to implement a new market has begun, no further IPP contracts should be entered into. In many countries, there is a chronic lack of generating capacity, system reliability is poor and demand is growing rapidly. In these circumstances, it is not realistic to expect investors to enter into commitments to accept full market risk at a time when the new market is still in the course of design yet new capacity is urgently required to avoid power crises. It is also unrealistic to expect investors to take market risk in the early stages of market operation when design flaws may need correction and the market operator and other participants are still learning the rules of the game.

A key transitional issue is one of how to attract necessary new investment in generation until the market is fully established. IPP contracts may well provide an appropriate answer in the minimum amount of time. The question is how they should be structured in order to ease integration.

Ancillary Services and Congestion Management

Most existing IPP contracts contain at best limited obligations to provide ancillary services and in no event pay the producer for providing them. Restructured markets unbundle ancillary services and producers who provide such services are paid for them.³⁷ At least some of the revenues which could be seen at risk for an IPP in a competitive market could be recovered through the sale of ancillary services. For example, market rules create a separate ancillary services market which is designed to incentivize market participants (generators in particular) to support the system operator in maintaining reliability and security of supply. The ancillary services will include frequency and voltage control, reactive power, reserves and black start capability. If the IPP plant has, for example, black start capability, it would be separately compensated for making it available.

In less developed countries where reliability is a serious problem, paying generators to provide ancillary services represents a small price to pay for an enormous saving in the costs of attempting to maintain some measure of system security and continuity of supply through crisis management. The benefits to the consumer and to the economy in terms of improved quality and continuity of service are considerable. Not only would the contract holder/power purchaser gain but so would the IPP. The IPP would be paid for a capability which may always have been inherent in its plant but which it has never been asked to provide or been paid for in the past. If market based pricing is a feature of the ancillary services market and the IPP develops the appropriate trading and operational skills, it should be able to ensure that its plant is able to provide the ancillary services at the times when prices in the market are high.

There may also be an opportunity for the IPP to make money under congestion management arrangements. The market rules may well involve payments to generators who are prepared to increase or decrease their generation in order to alleviate transmission system congestion. The prices paid may be bid based or they may be calculated according to some other formula involving opportunity cost.

³⁷ The rates may be based on competitively procured contracts (as in the early England and Wales Pool) or spot prices bid competitively, or a combination of the two (as in California).

Evolution to Merchant Plant Status

Until a power market has been well-established in a country, it will be difficult to attract investors to finance merchant plants that carry full market risk. One approach is to reduce the period of time during which the IPP is completely insulated from the market. There are at least two potential ways of doing this. First, instead of a capacity price fixed for twenty-five years, the price could be fixed for a shorter period of time, for example, five years. After that, the developer would take additional market risk each year. For example, the developer may take 20% market risk in year 6, 40% in year 7, and so on until the contract is completely at market. Second, bidders for new capacity can be required to submit bids based on a five-year, ten-year, and twenty-five year contract term.

While these approaches have appeal, there is a danger that the most likely response would be to bid the same net present value of the fixed price income stream, but for shorter periods of time. In any event, investors will require considerable confidence that the reform and the new market will be very well designed and implemented. They will want to be assured that prices cannot be manipulated to their disadvantage through abuse of market power and that there is a first class governance mechanism to ensure that the right corrections are made in the light of operating experience.

Symmetry in Buyout and Termination Clauses

Where a PPA is concluded in circumstances where a restructuring is in the course of implementation, the parties will inevitably focus on the buyout and termination clauses because of the uncertainties that the future holds. Traditional buyout clauses have compensated the developer for the unamortized portion of the future revenue stream. Under the typical buyout formula, the above-market portion of the contract is reduced to a present-valued lump sum with the developer being isolated from market risk and the purchaser being completely exposed.

The buyout clause should ideally be symmetrical, so that if the IPP developer thinks it can do better in the market than under the contract, it must pay the contract holder/power purchaser for terminating the contract and depriving the purchaser of the benefit of the bargain. The difficulty is that prior to the opening of the market it is not easy to craft a buyout formula acceptable to both parties based on anticipated market prices. A simple solution might be to maintain tracking accounts to establish the amount of money, which the IPP would have or has made in the market against that to which it is entitled under the PPA. The parties could simply split the surplus proceeds between them on a 50/50 basis. This would be carried out on an ex-post basis rather than on the basis of the projected market price mentioned earlier. Although the contract would not change financially, the presence of the IPP generation would enhance the liquidity of the market.

Specific Considerations

Choice of Successor Contract Holder/Power Purchaser

If the IPP contracts are not to be the subject of a contract buyout, it will be necessary to determine which of the new successor entities to the vertically integrated utility would be

the most appropriate contract holder/power purchaser. This decision involves focusing on the various functions of the contract holder under the PPA and contract manager.³⁸

As explained earlier, the contract holder is the contract party to the PPA, responsible for the performance of the obligations to the IPP (particularly funding payments and would also be responsible for the performance of the contract manager). The contract manager would act as intermediary between the IPP and the ISO and/or market coordinator (sometimes termed settlement agent), responsible for the day-to-day functions and activities arising under the market rules and the terms of the PPA. It would also be a marketer or retailer of the IPP output under the PPA. If the contract manager is organized as a profit making entity, it could be incentivized to minimize above-market costs and to look for solutions that would result in voluntary renegotiation of the IPP contracts in a manner that is mutually satisfactory to the parties. The incentives could include the ability to share an agreed percentage of cost savings, to keep savings achieved that are greater than a specified target or bonus for designing a formula acceptable to the parties that achieves some degree of market integration.

Evaluation of Potential Candidates

The main concern that arises in relation to the selection of a successor to the utility offtaker is the potential for the creation of conflicts of interest and whether they could be dealt with effectively through regulation to preserve the transparency and integrity of the market. The ISO is ruled out on this basis as it should operate independently of any trading in the marketplace. Similar concerns arise with the transmission company and a distribution company, which must provide open and non-discriminatory access to its system. A generator would be a potential competitor of the IPP and may, therefore, have a conflict of interest. An independent electricity retailer could be an appropriate candidate for either role. An independent, profit-motivated³⁹ company, established for this purpose would be ideal.

In Ontario, the residual, debt service successor company was chosen to be the power purchaser/contract holder. Its primary role was to manage and minimize the stranded costs associated with Ontario Hydro's considerable debt as well as to manage above markets costs associated with its 100 NUG contracts. It was free of any conflict of interest which would affect the transparency and credibility of the market. However, it did not have the necessary market skills to be the contract manager and would have had to outsource this function in any event. The role of contract manager requires real profit-motivation to enable incentives to be created to manage the contracts effectively to achieve IPP plant integration and to minimize above market costs.

Quantifying and Recovering Above-Market Costs

Reducing Above-Market Costs

The above-market costs arising from the pressure of competitive forces on existing plant represent a major challenge to the achievement of the goals of introducing wholesale power markets. Such costs must be borne by some combination of IPP generators, their

³⁸ The analysis gave rise to the virtual generation/managed contract approach utilised in Victoria and proposed for Ontario and Thailand.

³⁹ Profit-motivation is useful for the creation of performance incentives.

financiers, off takers, taxpayers and consumers. The reluctance of any group to bear what they perceive to be a disproportionate share of costs, particularly given the uncertainties in the evolution of a new power market, place a premium on creating devices to minimize above-market costs. Very few jurisdictions have attempted to do this either by adapting market rules appropriately or by incentivizing a contract manager to do so. They have simply established a mechanism to recover such costs, typically involving a levy on consumers. The cost-recovery mechanism generally requires :-

- quantification; and
- measures to moderate the impact on those who pay the costs.

This issue was a particularly sensitive one in Ontario, where Ontario Hydro's level of stranded debt was already extremely high and the very significant above-market cost recovery period associated with the NUG contracts could extend for the lives of those contracts and beyond the cost recovery period associated with the stranded debt. Interestingly, this concern began to evaporate when it was realized that the longer the period of recovery, the smaller the levy that the consumer would have to pay on a regular basis.

Measuring Above Market Costs

Present value approach: One approach to quantification is the "present value" approach in which above-market costs are calculated as the difference between the net present value of the average contract price and the current market price. However, this approach suffers from a major drawback in that it makes no room for movements in the market prices over the life of the asset. In short, the above-market cost of a long-term IPP power is not the same over time. It will fluctuate based upon movement of the variables that contribute towards its calculation, the most important of those variables being the market price itself.

Because the level of stranded costs varies inversely with the market price of power, and because the levels of predicted stranded costs can be staggering (in the entire US, total stranded costs were, at one time, estimated to be above \$200 billion), stranded cost recovery needs to be trued-up, periodically, to actual prices in the power market. Increased market prices contribute to this reduction in above-market cost. It would be viewed as inequitable to overcharge consumers and politically unacceptable to be seen to be reimbursing them any over- payment. The periodic reviews do however carry costs and may be subject to disputes.

Rebidding contracted capacity: If there is a contract buyout under a competitive process, the above-market costs would be crystallized in a more accurate way than the "present value" approach. Under the crystallization approach, the price that is offered by the successful bidder would form the basis for the calculation of the above- market costs⁴⁰. The advantage that this approach presents over the "present value" approach is that by definition, the value of the plant would be assessed based on market participants' (bidders) expectations as to future prices.

Where the above-market costs are crystallized in this way, these costs could be funded by raising necessary debt and securitizing that debt against future revenue streams from

⁴⁰ The crystallised above-market costs would essentially be the difference between the net present value of the average contract price and the price paid by the successful bidder.

consumers in the form of a levy and/or from the public purse if tax payers were to share in the costs of transitioning to a competitive wholesale power market. The latter approach would take the form of a reduced value of contract holder assets in the case of privatization/divestiture or compensatory payments to contract holders if no acquisition was contemplated. If the stream of revenue from consumers or tax payers was reasonably certain (eg. captive consumers), securitization may reduce the financing costs.

However, as already indicated, an immediate buyout at the time of introduction of the competitive market may place a high premium on the market risk that the new contract holder would be required to assume and, as such, may not have the full impact on reducing above-market costs. Once the market is reasonably developed, perceptions of market risk will be reduced and prospective buyers will be in a better position to quantify and assess it.

Real time valuation of differences: A third option is to determine the above-market costs in real time. In other words, the amount could be determined every hour of the day based upon the difference between the IPP contract prices and the price actually received for the power supplied by the IPPs in the wholesale market. Some forecasting would be required because certain of the amounts payable to the IPPs under their contracts (for example, the capacity payment) is calculated after the month to which any given payment relates. The implementation of this system requires detailed information to be made available to the market operator.

Pooling Stranded Costs

Once above-market costs have been quantified, they might be pooled with other stranded costs⁴¹. This would permit reductions in costs if one stream of stranded costs experiences unexpectedly favorable trends, resulting in stranded benefits rather than stranded costs, and the two could be offset against each other. "Stranded benefits" tend to arise when revisions in cashflow projections result in "excess" revenues beyond those required to meet all of the stranded costs. Pooling would help ensure that stranded benefits from whatever source would reduce the nominal above-market costs to be recovered from the consumers or taxpayers.

Recovery Through Transmission Tariff

Above-market costs may also be recovered through a levy added to the transmission tariff. In this situation, the transmission company acts as collection agent. The calculation could be carried out by the contract holder/manager or the transmission company if it is given the necessary data. This approach suffers from several disadvantages. For example, it does not provide for transparency. Consumers would not be able to identify the above-market costs of the IPP contracts as a separate component in their bill. It would also introduce a measure of volatility into the transmission tariff based on the IPP's performance, which would be confusing to market participants and consumers. If it were applied to wheeling transactions by purchasers connected to neighboring (interconnected) transmission or distribution systems outside the transmission systems of the new market, it would result in charging the associated external buyers or sellers, who should not be burdened by the above-market costs (because they were not involved in their creation and did not benefit

⁴¹ Examples of other stranded costs include the outstanding debt of the vertically integrated utility that is being restructured, which may be publicly held (e.g. by bondholders) or above-market costs associated with utility's own generating plant which is not competitive with other plant in the market.

from the IPP plant in the past). It might also reduce the competitiveness of generators who wish to export electricity outside their jurisdiction.

On the other hand, there are certain advantages. For example, it is the mechanism that is least open to by-pass. In other words, a consumer cannot avoid paying the levy because all consumers will be paying, directly or indirectly, an amount in respect of their use of the transmission system.⁴² Moreover, it does not upset competitive relationships. The other advantage is that it should be relatively easy to collect through the ISO or transmission company, without imposing excessive administration costs.

Approaches in Developing Country Contexts

The goal of most countries in integrating IPPs into electricity markets center on:

- creating a liquid, efficient and competitive market;
- minimizing above-market costs associated with IPP contracts and their impact on the consumer.

However, the initial conditions of developed and less developed countries often differ. The typical features in developing countries are:-

- strong demand growth;
- backlog of under-investment;
- low retail tariffs that are not cost-reflective;
- lack of financial resources (including currency risk, lack of liquidity);
- exceptionally high institutional, political and regulatory risk.

This will mean that the steps on the way to reform may have to be taken more gradually and the design of the market should, at least initially, be relatively less complex than in some developed countries.

Choice of Approach for Developing Countries

A developing country should begin by taking positive steps to make it clear to all stakeholders and potential investors that the reform will be well designed and implemented and that their concerns will be addressed. If there is no confidence that the government is serious about doing the job properly it will lose credibility.

The most challenging scenario for any developing country is where there is strong demand growth, an urgent need to attract new investment and existing IPP plant that represents a significant proportion of the more flexible, efficient and cheaper capacity on its system. It would clearly be desirable to integrate the IPP plant into the market. The solution, in this scenario, could involve a combination of approaches:

⁴² It might be that the market design would allow market participants embedded in a distribution system which purchase only from an embedded generator to avoid paying transmission charges. However, there are relatively few examples where the design does allow for this. If it does, a special rule would have to be created to avoid by-pass of a stranded cost levy included in transmission charges.

- (a) facilitate voluntary renegotiation to encourage the IPP to participate in the market at least with respect to uncontracted capacity and energy and also ancillary services and congestion management;
- (b) adapt the market rules preferably for a transitional period to accommodate the IPPs to the extent possible without compromising the competitiveness and efficiency of the market and exempt them from the requirements to comply with rules and standards which do not affect reliability, particularly if these have cost implications;
- (c) appoint an experienced and skilled contract manager to manage the PPAs for the power purchaser/contract holder, but one which is incentivized to facilitate integration and minimize above-market costs;
- (d) consider the potential benefits of a contract buyout at a point in the future, once the market has settled down, on the expectation that there will be sufficient interest from suitably qualified bidders prepared to take a substantial degree of market risk without discounting the prices they are prepared to bid excessively;
- (e) establish a transparent and credible process of discussion and consultation with IPPs in relation to the measures outlined in (a) - (d) above; in order to reassure IPPs, their lenders and investors.

Conclusions

Development of the Ideas and Solutions

This paper outlines a range of issues and options to ease the integration of IPPs into new electricity markets. More work is needed to develop practicable strategies based on in-depth evaluation of experience to date in specific country circumstances. Among the most salient topics are:-

- Assessment of operational experience, including quantification of financial outcomes in those countries that have attempted to deal with IPPs to achieve market integration and/or minimize above-market costs;
- Case studies of financial and operational implications for countries which have a significant proportion of IPP plant on the system and which have not dealt with market integration or above-market costs;
- Specification and modeling of alternative market rules to accommodate IPPs on a transitional or long term basis;
- On case study basis, identify and evaluate tradeoffs/synergies between good grid management and market liquidity with specific transitional provisions in IPP contracts designed to ease integration into new markets;
- Elaboration of facilitation processes to achieve the successful outcome of a voluntary renegotiation of IPP contracts;
- Quantitative evaluation of the distributional impact of various options on key stakeholders: IPP shareholders, offtakers, taxpayers, and consumers.

The Role of Government and Regulators

In tackling the integration of IPP contracts into power markets, governments and regulators must command credibility with the IPPs, their lenders, investors and other market participants. Experience to date strongly indicates that unless IPPs are convinced that the issues will be handled in a fair and transparent manner, they will refuse to cooperate in integrating or renegotiating their contracts.

This places the onus on governments and regulators to implement a well thought through communications strategy and manage a process that is perceived to be fair, transparent and open, consulting affected stakeholders from the start. They must develop the reputation, through their actions, for being fair but firm. This will require that they equip themselves with the appropriate knowledge and expertise.

Equally important is sound design of market structures and rules. Manipulating the design to accommodate the fears or pre-occupations of a particular stakeholder group, industry incumbent or a political dogma will not produce a market that is workable or which provides a level playing field for the forces of competition to achieve efficiency gains and drive down costs/prices for the benefit of the consumer.

From the perspective of the consumer, it must be worth making the effort to integrate IPPs into new markets and to minimize the associated above-market costs. Indeed, partial integration will be better than nothing e.g. participation in ancillary services markets or congestion management measures even if IPP energy is not initially traded in the new market. However, there may be scope for trading uncontracted capacity and energy if the quantity is significant.

It clearly is in the realm of the possible to change some of the variables referred to in this note even if re-negotiation of the IPP contracts themselves proves to be difficult, e.g., changing market rules to facilitate integration over time and appointing a contract manager, incentivized to minimize the above-market costs. These measures, however modest will, in the long run benefit the consumer and the economy at large.

Ultimately, integrating IPPs into markets is a transitional issue. The time will come when the market is sufficiently stable that IPPs will participate in it on their own volition and take increasing market risk. Other market participants will then be willing to buy out the IPP contracts or plant at prices that minimize above-market costs. The question of existing IPP contracts should not be allowed to deter the market reforms. There are a number of potential solutions to be created through modification of market rules, contract management arrangements, and IPP contractual obligations and remunerations. Governments must make a sustained, concerted effort to deal with the issues and to treat the parties fairly. The payoff to the country involved is realizing significantly greater productive and allocative efficiencies .

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Annex 1

International Experience of Integrating IPPs into Electricity Markets

- (a) **California** has a significant quantity of IPP and QF plant ⁴³. Most of it was contracted to the three large investor-owned utilities who, as purchasers, were simply required by the regulatory regime to bid that capacity and the energy produced into the new Power Exchange (PX). The distributors that purchased through the PX were permitted to pass these wholesale costs on to their customers (although they were also subject to an initial rate freeze). Also, certain exemptions were incorporated into the market rules to accommodate some of the IPP and QF plant which the regulators designated as “must take” plant. Accordingly, while the QFs are integrated into the market, in that their power is accepted, they are not economically integrated. If their contracts are inflexible, the plants are not dispatchable. In sum, the market merely accommodates the QFs rather than integrating them.
- (b) **Victoria** implemented a successful reform program and market structure (based on the England and Wales model) and assigned each of the PPAs entered into with IPPs to one of four “PPA Traders” which resold the output of the IPP plant in the market. This is described more fully in the main text of this paper.
- (c) **Northern Ireland** put in place the single buyer model and sold its existing generating plant to three IPPs which sell power to the single buyer (a combined wholesale purchaser/bulk supplier, transmission and distribution company) under 15 year PPAs. The regulator has been anxious to introduce more wholesale competition. A mechanism has been introduced where wholesale buyers can purchase surplus capacity directly from the IPPs as “virtual generation” and sell the energy to non-captive, large customers. This has involved intensive but not very productive, renegotiation of some very sophisticated, long term PPAs.
- (d) **Portugal** has two new large IPP plants on its system accounting for around 35-40% of its capacity which recently came into service. They are cheaper and more efficient than any of the other plant. In 1993, it designed its reform process and a single buyer market structure around these IPPs. The plant is fully dispatchable and must provide ancillary services and congestion management measures⁴⁴. In response to concerns from the European Union competition authority that the model was not competitive because all of the IPP and existing plant was contracted to the single buyer, the Portuguese created a second “free market” along side the single buyer “binding” market in which IPPs could build plant and sell to a category of large customers eligible to choose their producer. So far no

⁴³ The QF PPAs were based on high prices set administratively and without regard to the need for capacity or energy.

⁴⁴ These requirements may make it easier for the contract holder/power purchaser to comply with the market rules but not to renegotiate the PPAs or incentivize the IPPs to take market risk.

plant has been built in the free market (apart from some micro-hydro plant).⁴⁵ The Portuguese Government has recently announced plans to reform this structure.

- (e) **Guatemala** commenced a program to restructure and privatize its electricity industry between 1997-1999. Though it is a small country, it had 11 IPPs on its system, protected by first generation power purchase agreements which did not reflect the power purchaser's role as system operator. Many of the IPPs were financed by foreign investors and lenders.

Although the legislation and regulatory regime purported to require integration of all plant connected to the Guatemalan transmission system to participate in the new market, the IPPs chose to rest on the protections afforded to them by their power purchase and other agreements. The government, regulator and power purchasers wished to adopt an approach under which they would look for "win-win" solutions that would encourage the IPPs to participate in the market, at least in part.

No actual or implied coercion by the government, the regulator or the power purchasers/contract holders was intended. However, the IPPs were alarmed by the prospect of contract renegotiation and it has so far not proved possible to entice them to the negotiating table.

- (f) **Poland** is proposing to put in place a stranded cost recovery mechanism which will cover the above-market costs of IPP plants as well other stranded costs. The other stranded costs comprised long-term contracts for about 70% of Poland's capacity and are related to investments made by state-owned power companies in equipment designed to reduce emissions to meet environmental requirements. The recovery mechanism involves an additional charge or levy being made through the transmission tariff, payable by all distributors and other transmission users. While there has been no attempt at this stage to put in place mechanisms that are designed to encourage or facilitate integration of IPP plant into the planned wholesale market, there are indications that Poland will look to PPA renegotiation to reduce stranded costs. IPPs with more efficient plant already recognize that they will probably want to participate in the new wholesale market at a relatively early stage once the market has settled down and are already planning for this.

Because there is little experience of countries being proactive and it is not possible to assess and compare the outcomes of those countries that have attempted to integrate IPPs into the markets using different techniques. Of the countries mentioned in this paper that have made the attempt:

- (i) Victoria probably is the most successful but there is no cost-benefit analysis available to indicate what the consumer has gained or lost;
- (ii) Portugal has created a market structure that integrates its IPPs in a single-buyer model that is not regarded as particularly competitive; and

⁴⁵ A similar regime exists in Panama.

- (iii) Northern Ireland has found it nearly but not quite impossible to achieve more competition in the single-buyer model that it has implemented.

Annex 2

Modification of Market Rules

Analysis of the Gap Between Relevant Market Rules and Typical PPA/Rules/Provisions

Rule/Provision/Requirement	1st Generation PPA	2nd Generation PPA	Market Rules
1. Planning information/studies	x	x	✓
2. Operational information/security assessments/studies	x	x	✓
3. Operational requirements (e.g. staffing, synchronisation)	x	✓ ¹	✓
4. Plant data registration	✓ ¹	✓	✓
5. Connection/interconnection facilities and procedures	✓ ¹	✓ ¹	✓
6. Availability declarations/bidding	x	✓	✓
7. Scheduling procedures	x	x	✓
8. Temporary revisions to dynamic parameters/operational capabilities	x	✓ ¹	✓
9. Dispatch procedures	x	✓ ¹	✓
10. Ancillary services (including reserve and frequent control)	x	✓ ¹	✓
11. Congestion management	x	x	✓
12. Incentives/payments for ancillary services/congestion management	x	x	✓
13. Outage planning and coordination	x	✓ ¹	✓
14. Testing and monitoring operating characteristics, connection facilities, availability, provision of ancillary services	x	✓ ¹	✓
15. Communication facilities and procedures	x	✓ ¹	✓
16. Metering	x	✓ ¹	✓
17. Negative power margins (output reduction priorities)	x	x	✓
18. Operational liaison, events, incidents	x	x	✓
19. Emergencies and contingency	x	✓ ¹	✓

Rule/Provision/Requirement	1st Generation PPA	2nd Generation PPA	Market Rules
planning			
20. Safety coordination	x	x	✓
21. Disconnection	x	x	✓
22. Consequences of non-compliance/liability	✓ ¹	✓ ¹	✓
23. Confidentiality	✓ ²	✓ ²	✓
24. Force majeure	✓ ²	✓ ²	✓
25. Audit	x	x	✓
26. Dispute resolution	✓ ²	✓ ²	✓
27. Prices, settlements and billing	✓ ²	✓ ²	✓
28. Prudential requirements (payment default protection)	x	x	✓

- Notes:
1. Provisions likely to be considerably less detailed or demanding.
 2. Provisions likely to be inconsistent with market rules.

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